

2002-2012 Electricity Outlook Report -- Executive Summary

This report assesses California's electricity system over the next ten years, focusing on supply and demand forecasts, reliability, wholesale spot market and retail prices, demand responsiveness, renewable generation initiatives, and environmental issues. Part I, *Setting the Stage*, includes background information to understand the electricity market developments over the last three years and a supply adequacy assessment for the next three years. Part II, *California's Electricity Demand and Supply Balance*, discusses how key uncertainties affect our ability to make longer-term forecasts of electricity demand, supply adequacy, and wholesale electricity prices. Part III, *Issues Analyses*, explores how the current state of the electricity market is affecting prospects for sustaining adequate generating capacity, retail electricity rates, the development of demand responsive loads and renewable generation, and the environmental review of proposed power plants.

Scope and Purpose

The *2002-2012 Electricity Outlook Report* is a product of the Energy Commission's ongoing responsibilities to evaluate California's electricity demand and supply and to assess electricity system issues. Its purpose is to provide the Governor and Legislature an assessment of the state's electricity system over the next ten years and information on issues impacting state electricity issues. In addition, the results of this report will be available within the timeframe needed to meet the Energy Commission's obligation, under Section 3369 of the Public Utilities Code, to coordinate with the California Consumer Power and Financing Authority's development of its Energy Resources Investment Plan. This obligation was enacted in Senate Bill Number 6X, which was signed into law by Governor Davis. (Stats. 2001, 1st Ex. Sess. 2000 - 2001, ch. 10.)

This study helps to inform generation and demand decisions that could be made within the next two years by analyzing their possible intended and unintended consequences through the rest of the decade. The study necessarily examines the entire West, but focuses on electricity market trends and issues within California.

This report provides analyses that will help identify the choices and constraints, alternatives, implications and proposed actions that will further the goal of balancing electricity system reliability, reasonable prices and environmental protection. To meet this goal in a sustainable fashion, the long-term impact on suppliers, consumers and the environment must be carefully considered. Based on current supply and demand assessments, the Energy Commission believes that the near-term outlook for supply adequacy is promising. This gives California breathing room to examine the opportunities

and choices for meeting its environmental, efficiency, and renewable resource investment goals.

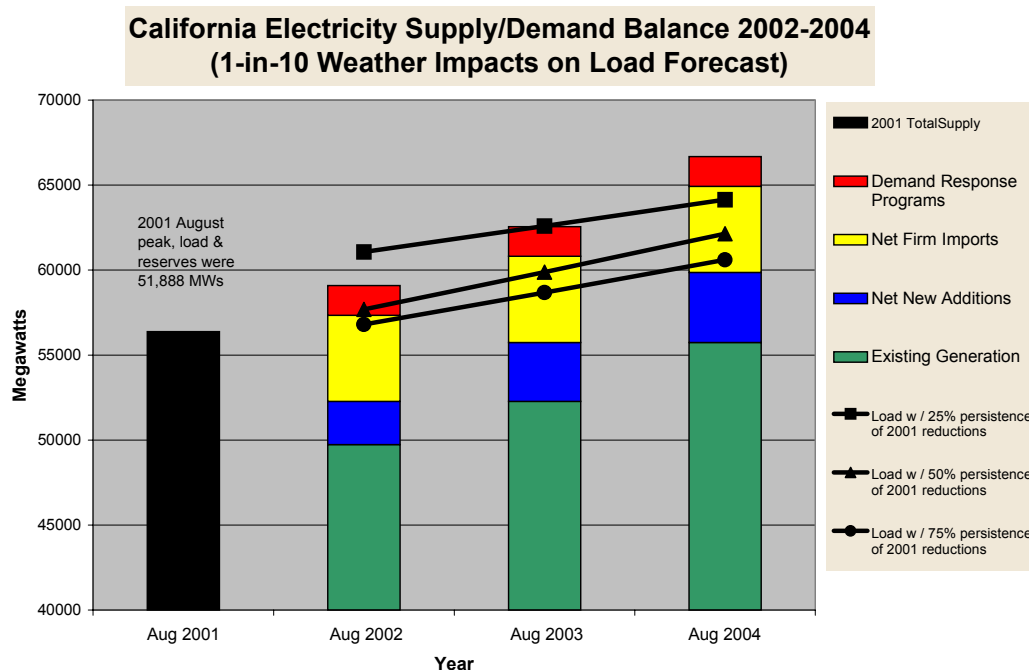
The remainder of this "Executive Summary" summarizes the analyses, findings and conclusions discussed in the report.

Part I: Electricity Market Developments - Setting the Stage

Part I summarizes the factors that have created the market volatility of the last several years and the events that have allowed the market to stabilize this summer. In addition, this chapter provides an electricity supply outlook of the expected near-term trends.

Based on the Commission's analysis, the electricity outlook for the next several years is more favorable for maintaining system reliability and moderating wholesale prices. **Figure ES-1** highlights the near-term capacity supply outlook. Although the outlook has improved for maintaining system reliability through 2004, several issues still need to be resolved. Many of the market structure changes made to avert the near-term crisis actually compromised some of the intended long-term goals of restructuring and have raised issues about the long-term sustainability of system reliability and moderate electricity prices.

Figure ES-1



The market structure that currently exists is an *ad hoc* arrangement, created to respond to the immediate needs of the crisis that was averted. If pending electricity related financial issues are not resolved and positive steps towards fixing the market structure are delayed, California will most likely face long-term system problems. Policy makers now have to choose what market organization and market structure will best serve California. What should the new market look like? Will it still have a strong competitive flavor or will the State assume a larger role in procuring future power supplies? Does the State need to have a "reserve," and if so, what form should it take and how large should it be? These questions need to be carefully analyzed and thoughtfully addressed.

Part II: California Electricity Demand and Supply Balance

This chapter presents the component analyses comprising the overall electricity supply and demand assessment for the next decade. Chapter II-1, California Electricity Demand, examines the uncertainties associated with forecasting the California electrical system peak demand and energy requirements, given the substantial reduction in consumer demand in response to the recent electricity crisis.

Chapter II-2, Energy Market Simulations, examines the uncertainties associated with forecasting energy spot market prices and new power plant completions under a variety of supply and demand scenarios. Even with much of the energy demand served under bilateral contracts, spot market prices remain an important price signal for developers of new supply- or demand-side electricity resources. The goal of this analysis is to estimate spot market prices, which can be used to assess the likelihood of additional capacity expansion and the retirement of existing power plants.

Chapter II-3, Putting the Risks of Capacity Shortages in Perspective, presents a probabilistic analysis of the potential risks that near-term (2003) capacity resources may be inadequate to meet demand and reserve requirements. This chapter's goal is to understand how robust is the more deterministic supply adequacy assessment found in Part I. This chapter also examines the differences in supply adequacy risks among the various transmission-constrained areas of the state (this was not a feature of the Part I supply assessment).

Chapter II-1: California Electricity Demand

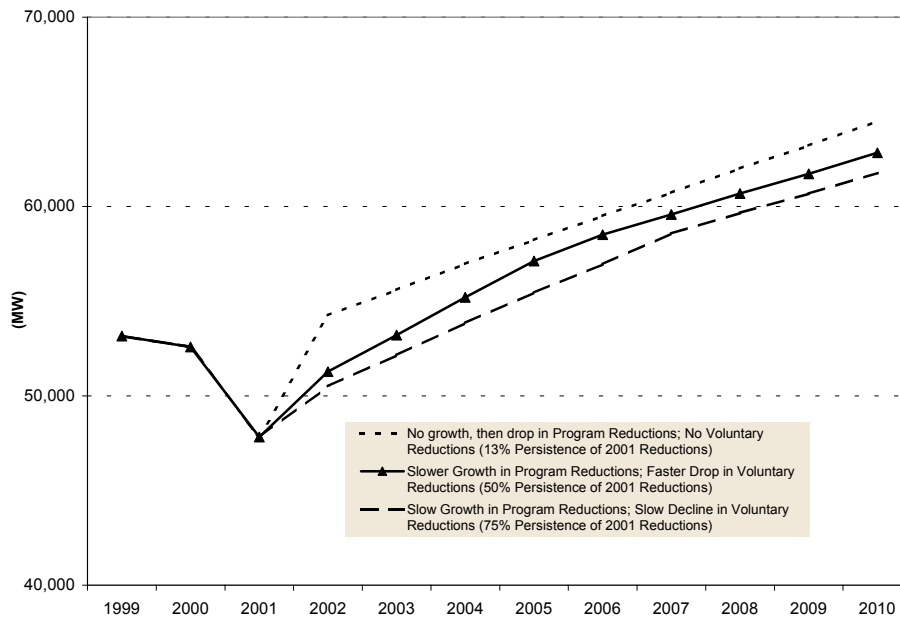
The summer of 2001 saw an extraordinary reduction in peak demand. Even though the summer of 2000 and 2001 were equally hot, actual summer peak demand in 2001 was substantially lower than in 2000. There were 29 days during the summer of 2000 when demand exceeded 40,000 MW. There were only 6 of these high demand days during the summer of 2001.

The following summarizes our analysis of expected California energy consumption over the coming decade:

- Uncertainty about future economic conditions makes forecasting highly uncertain.
- There is uncertainty regarding why summer of 2001 demand reductions occurred although electricity price increases, programs, and volunteerism are factors reducing summer 2001 demand.
- Impacts of demand reduction programs may increase slightly but, unless there are new campaigns or crises, voluntary demand reductions will likely decrease over time.
- The full impact of rate surcharges and newly legislated programs have not yet been seen.
- It is not clear what, if any, effect recent events will have on economic growth in the state — and on energy growth.

To capture this uncertainty about future electricity use, the Commission Staff developed several possible patterns of future trends for the persistence of summer 2001 demand reductions. These patterns are based on alternative assumptions about the level and persistence of voluntary impacts and permanent, program impacts (**Figure ES-2**). These three demand scenarios provide the demand forecast for the different analyses throughout this report.

Figure ES-2
California Electricity Consumption Scenarios



As well as detailed data about customer use, information is needed to determine why customers did what they did. Surveys need to be done to analyze how much of the reduction was due to customer behavioral and permanent response to legislated programs, how much was due to media campaigns, and how much to other factors. A better understanding of 2001 will reduce some of the uncertainty in the projections of future demand reduction.

Chapter II-2: Energy Market Simulations

This chapter presents five different scenarios simulating the wholesale spot market for electricity. The goal of this analysis is to obtain estimates of spot market prices, which can be used to assess the likelihood of additional capacity expansion (beyond what is already very likely to occur) and the retirement of existing power plants. The scenarios are differentiated by their assumptions about demand growth and new power plant additions during the next four years. The assumptions that characterize each scenario are discussed in detail. The simulation results are presented and discussed, including the spot market prices yielded by the five scenario simulations and the impact of power plant additions on the hours of operation of new combined cycles, peaking units, and the older and larger gas-fired plants. The chapter concludes with a discussion of the implications of the findings for the construction and retirement of capacity during the second half of the decade.

The long-term power contracts signed by the California Department of Water Resources to supply customers of the three largest investor-owned utilities, together with energy from utility-owned nuclear and hydroelectric generation and QF contracts, greatly reduce the share of energy to meet IOU customer demand purchased in spot markets. Accordingly, spot market electricity prices will play a significantly smaller role in determining the wholesale cost of energy for IOU customers. Spot market prices will continue, however, to have a major influence on the decisions to build new generation capacity and to retire existing facilities.

Low spot market prices, those that do not result in profits high enough to warrant investment in new plants, deter capacity expansion. If low enough, spot prices encourage the retirement of plants that cannot cover operating costs. High prices signal the need for new capacity and its profitability. Our results tend to indicate that the addition of expected new capacity during 2002 - 2005 is apt to drive spot market prices to levels that will render many existing power plants unprofitable and discourage further construction. However, there are factors that may encourage building even in the face of low prices in the short-term.

The simulation results also indicate that low prices from 2003 onward may be an incentive to retire existing units. It is unlikely, however, that a substantial

amount of capacity will be completely retired and dismantled in the WSCC during 2002 – 2004. Uncertainties related to the amount of new capacity coming on-line, the return of electricity demand to previous trend levels, and regulation and market structure will contribute to uncertainty regarding spot market electricity prices, and discourage the closure of generation facilities. Owners are apt to incur the costs required to keep less-efficient plants available for operation given the *possibility* of adequate revenues during the next couple of years, if not long-run profitability. Low prices in 2003 and 2004, would lead to reduced operation for many plants. This reduction in their competitiveness will encourage their placement into long-term reserve, and increased consideration being given to their retirement

As gas-fired power plants become an increasingly large share of the generation resources in California and the WSCC, the price of natural gas will have an increasingly larger role in determining the spot market price of electricity.

Overbuilding and delays in retiring older facilities are part of a “boom-bust” dynamic that is an inherent part of the structure of the market. The amplitude and length of these cycles cannot be known in advance, but must be considered in market design.

Chapter II-3: Quantifying the Risk of Capacity Shortages

Generally, the power system is said to have adequate capacity if it has enough generation and transmission resources to meet the customer demand and to maintain a reserve of capacity for contingencies. But it would be prohibitively expensive to build an electric generation and transmission system that would *never* experience a service outage. Instead, we seek to minimize outages within a constraint of reasonable cost, thereby accepting some risk of outages.

The goal of this chapter is to understand how robust is the more deterministic supply adequacy assessment for 2003, found in Part I, by applying more probabilistic risk assessment techniques. In doing so, we illustrate the risk issues that are central to the questions: What risk of supply shortages are we facing in the near term? Do we have "enough" capacity? How much additional risk will the next increment of capacity avoid? What are our options for managing the risk, and how do their risk management performances compare? In addition, the risk assessment in this chapter examines the differences in supply adequacy risks among the various transmission-constrained areas of the state, which was not a feature of the previous supply assessments.

This chapter specifically illustrates how uncertainties associated with specific key risks that affect supply adequacy contribute to the overall risk of supply shortages. (By "shortage" we mean failing to maintain a seven-percent reserve; we do not mean experiencing a service outage of firm load.) We assessed one demand-side risk to supply adequacy: the effect of temperature variations on

peak demand. We assessed three supply-side risks: the effect of hydrological conditions on the availability of hydroelectric generation capacity, the effect of potential construction delays on the availability of new power plant capacity, and the effect of aging on the rates at which generation and transmission facilities are forced out of service. We selected the summer of 2003 as the time period to illustrate the risk assessment because the supply balance was tightest that year and sufficient time remains to take additional action, should that be warranted.

Generally we have found that our probabilistic risk assessment gives us a measure of confidence in the near-term supply adequacy outlook in Part I. Although this work does identify the *possibility* of shortages in excess of those identified in Part I, the probability of their occurrence is generally small. The risks of power supply shortages in 2003 vary for different parts of the state: from little to no risk for Northern and Central California and the largest municipal utilities- LADWP and SMUD, to low risk (about 1 percent) for Southern California, to a noticeable level of risk (7 percent) for San Diego, and to a significant level of risk (about 14 percent) for San Francisco.

Depending on the cost to society of such shortages, actions in addition to those anticipated in the Part I near-term supply analysis might be taken (and their associated expense incurred) to avoid the additional risk of shortages. A cost-benefit analysis of available "supply adequacy insurance" options has not been attempted in this report. However, we do make the case that, if supply adequacy insurance is sought, then the full range of demand- and supply-side options for mitigating that risk should be considered.

Part III: Issues Analyses

This part presents discussions and analyses of a variety of issues important to the development of a workable electricity market. Chapter III-1, Electricity Markets and Capacity Supply, deals with the fundamental question of how well the existing energy market can be expected to maintain the adequacy of the electricity system at reasonable prices, and what market changes might better achieve that goal. Chapter III-2, Retail Electricity Price Outlook, provides an assessment of future retail electricity rates by utility and customer class, showing how the various components of costs each contribute to the total rate. Chapter III-3, Developing Demand Responsive Loads, examines the characteristics of the demand response potential, and suggests a specific mix of load curtailment programs to ensure reliability in the year 2002. Chapter III-4, Effects of Renewable Generation Initiatives, discusses how recent events and the current *ad hoc* market arrangements have affected the renewable generation industry and issues related to incentive programs for developing renewable generation resources. Chapter III-5, Siting Issues, describes the progress the Energy Commission has made in licensing new power plants, issues that may

affect the ability of power plant developers to obtain timely approval; and measures needed to address these siting issues.

Chapter III-1: Electricity Markets and Capacity Supply

This chapter examines what structure will motivate the addition of timely new supply to reduce price volatility and contribute to reliable service. Three options for revising the supply market for capacity are introduced and evaluated. This chapter also finds that modifications to retail pricing and to the wholesale market are also necessary for a sustainable generation market. Unless modifications are made, by 2005 California will be headed back into supply and demand conditions likely to produce tight supplies, price volatility, reliability concerns, and consumer dissatisfaction.

Choosing a method to ensure future adequate supply is a major element of the 2002 market redesign. Tight capacity supplies were one of the principal conditions that allowed the California market to destabilize. The current market structure must be changed, because it cannot produce adequate generation in a timely and efficient manner. Under the current market structure California is doomed to boom and bust cycles, price spikes, price volatility, and higher prices due to the need to hedge against the risks inherent in a faulty market design. A good market design will provide benefits to consumers and suppliers, allow for efficient market monitoring, reduce the need for government intervention, and promote competitive innovation. Policy-makers now have to choose what market structures will best serve California.

Three supply designs are evaluated: incentive payments for reserves, installed capacity requirements and a regulated, cost-of-service capacity reserve. Of the three, the installed capacity requirement is the most promising. But its actual effectiveness is dependent on complicated implementation rules. Hundreds of millions of dollars are at stake in these design details. Further exploration is needed to determine the most effective capacity payment options

The wholesale and retail market structures are interdependent. Effective generation price signals cannot take place independent of price responsiveness in the retail market. Consumers must choose to consume or not consume based on prices that reflect market conditions. They may make this choice directly through their own real-time pricing actions or through their utilities/aggregators that would hold a hedged portfolio to provide rate stability.

Generation adequacy will be facilitated if the wholesale day-ahead, hour-ahead, and real time spot markets use commercial models that reflect physical constraints and efficient dispatch. Generators must have an obligation to perform according to schedules. Accurate locational prices are needed.

The market structure must be compatible with other market designs in the Western United States. California is an integral part of a regional market. A coherent market design will need to be advocated in multiple forums, including FERC, the ISO, CPUC, CPA, and DWR. New California laws will be needed to facilitate a new design.

Chapter III-2: Retail Electricity Price Outlook

This chapter presents the Energy Commission's outlook of electricity retail rates for California Investor- and Publicly-Owned Utilities for the years 2002-2012. In this outlook, the Commission provides estimates of the retail electricity rates that typical consumers may pay, given projected energy prices, utility plans and programs, and regulatory decisions. This outlook provides consumers, market participants, and policy makers with a basic understanding of the determinants of future electricity rates.

This outlook is not an absolute prediction of what the future electricity rates will be, since future regulatory actions, technology development, or market changes may alter key fundamental assumptions. Retail electricity rates detailed in this chapter reflect the best available information to Commission staff up to mid-November 2001 and a set of assumptions the authors believe probable and realistic. Since then, the California Public Utilities Commission has rendered some decisions that have a direct impact on the IOU price outlook. In addition, Southern California Edison provided comments and data to Commission staff that could also change the outlook. The Commission has directed the Staff to incorporate relevant data and information in an update of retail electricity prices within the next two months.

Under the circumstances specified in this chapter, retail rates for investor-owned utility (IOU) customers will most likely increase in the 2002-2003 period. A rate decrease is unlikely, unless the Federal Energy Regulatory Commission (FERC) orders merchant generators and energy traders to refund the State utilities for overcharges incurred during the fall 2000 and the winter 2001. However, a small rate decrease is possible after 2003 for most IOU customers. Municipal utilities are likely to maintain constant retail electricity rates for their customers during the 2002-2003 period. Rates for municipal customers after 2003 would most likely reflect the utilities' cost of generation, which under current projections will increase slightly every year through 2012.

Future retail electricity rates for the IOUs depend to a certain extent on the regulatory decisions of the FERC, the State Legislature, the Governor, and the CPUC, rather than the spot market prices. Most of the IOU electricity rate components are relatively set for the next ten years. Therefore, major rate fluctuations are unlikely.

Because municipal utilities have long-term contracts for energy, their rates depend more directly on the price of natural gas and to some extent the need to replenish their rate stabilization funds.

Chapter III-3: Developing Demand Responsive Loads

This chapter discusses the characteristics of the demand responsive potential, and suggests a specific mix of load curtailment programs to facilitate ensuring reliability in the year 2002. As Chapter III-1 of this report noted, the wholesale and retail market structures are interdependent. Effective generation price signals cannot take place independent of the retail market. Consumers must choose to consume or not consume based on prices that reflect market conditions. They may make this choice directly through their own real-time pricing actions or through their utilities/aggregators that would hold a hedged portfolio to provide rate stability. Further, in assessing the tradeoffs between demand response and peaking generators, the Commission believes that large amounts of DR loads can be acquired that are cheaper than peaking generators. This chapter assesses different types of demand responsiveness options and recommends pursuit of an aggregate capability of 2,500 MW through new and/or revised program designs.

Reducing exposure to excessive market prices is likely to be more cost-effective through time than avoiding markets entirely by relying upon command and control decision-making. Reducing exposure is not the same as eliminating exposure. Reducing exposure to excessive prices admits that an occasional dose of high prices in the right circumstances might be the most cost-effective way to satisfy net electricity demand with generation.

Demand response can come from real-time price (RTP) tariffs or dispatchable load curtailment programs that enable end-users to respond to market prices or to adverse system conditions by reducing loads, respectively. Customers on real-time price tariffs either save money by reducing consumption in high-priced periods or shifting loads from high- to lower-price periods. Customers on load curtailment programs respond to incentives to reduce loads when system conditions trigger load curtailment program operation. Both forms of demand responsiveness reduce loads when market prices and/or system conditions warrant this action.

Much remains to be determined about end-users' willingness to participate in demand responsive programs and tariffs. Unfortunately, we learned nothing in the summer of 2001 except that constantly changing program designs create great confusion in end-user minds and greatly increases the difficulty of marketing any programs. Our experience base with end-user response to demand responsive programs and rates is simply insufficient to be able to guarantee response. However, recent experience shows that at least some customers are perfectly willing to trade off reliability for reduced costs. Making

short term commitments to load curtailment programs achieves the overall goal of 2,500 MW of demand responsive capability, and can lead eventually to greater reliance upon RTP tariffs and less reliance upon load curtailment programs. The Energy Commission has already proposed specific modifications to two existing, CPUC-authorized load curtailment programs that would enable this 1,000 MW of increased load curtailment program capability to be achieved.

Chapter III-4: Effects of Renewable Generation Initiatives

This chapter discusses renewable energy issues arising from the recent changes in the electricity market conditions. Despite substantial Energy Commission *contingent* funding for new renewable facilities through the Public Goods Charge, the current absence of a market for the output of those facilities is threatening the long-term viability of the renewable industry. The Commission's Renewable Energy Program presently has agreements to provide production payments to 1,300 MW of new renewable capacity, *but only after projects come on-line*. How much of that capacity comes to fruition, however, is dependent on whether project developers can find a buyer for their power.

As a result of the electricity crisis, the market opportunities available to renewable facilities have been dramatically altered. The Power Exchange has disappeared. Utilities are either unable or unwilling to buy. Direct Access has been suspended, so selling to a "Green" Electric Service Provider is no longer an option. The Department of Water Resources contracted for only small amounts of renewable energy, and has ceased making long-term commitments. The newly created Power Authority is not yet in a position to finance or acquire renewable resources.

There are a number of activities underway in various forums that could potentially alleviate the no-market dilemma. The Legislature may enact a Renewable Portfolio Standard, the California Public Utility Commission's current utility procurement proceeding could result in a renewable purchase requirement, a renewable-only form of direct access may be restored, or proposals emanating from the California Consumer Power and Conservation Financing Authority might provide a remedy. But until suitable buyers for renewable energy materialize, there will continue to be a cloud over the future development of new renewable facilities.

The legislation extending the Energy Commission's renewables program stated renewables would add needed generating capacity while promoting diversity and reducing the need to burn fossil fuels. The Energy Commission has established a target of meeting 17 percent of California's energy demand with renewables by 2006. To respond effectively to changing conditions, the Energy

Commission needs to maintain its flexibility in determining the allocation and distribution of funds for its efforts in renewable energy.

Chapter III-5: Siting Issues

In response to the energy crisis, the Energy Commission has taken steps to expedite the licensing of new power plants. This chapter discusses these recent changes to the licensing process, current trends in licensing power plants, the interactions of transmission constraints with power plant licensing, the outcome of the new expedited review process, and remaining constraints to power plant licensing. This chapter finishes with suggestions to help alleviate some of the licensing constraints.

During the electricity emergency, the Energy Commission was successful in bringing new capacity on line by conducting early site screening for the emergency projects, assisting developers in processing project compliance amendments, and overcoming roadblocks to completing construction.

The Energy Commission will support efforts to improve planning for new generation and transmission lines to address congestion, system reliability and efficiency issues. Forecasting the electricity supply and demand balance requires more than a calculation of demand and supply. It also requires the assessment of the locations of demand increases and of new generation resource additions to avoid local transmission system congestion and generation deficiencies. Integrated electricity planning, which considers both transmission and capacity solutions should continue so the most economically efficient and reliable supply / demand balance has a better chance of being achieved.

The Energy Commission will continue to support consolidation of transmission line permitting in California. Although the Energy Commission licenses transmission lines needed to interconnect a power plant under its review to the transmission system, other transmission projects are permitted by multiple agencies. The overlap, inconsistency and inefficiency created by such permitting pose potential constraints to expedited licensing of new generation and transmission projects.

Environmental and permitting issues potentially constrain the Energy Commission's ability to site new capacity additions efficiently without resulting in contested proceedings or potentially significant adverse impacts. These issues include the availability of emission offsets, water supply and water quality impacts, the timing of federal permits, land use conflicts, transmission congestion, and natural gas supply constraints. Working with other agencies, the Energy Commission directs its Policy Committees and Staff to provide guidance or assistance regarding these constraints on licensing new capacity.